DIRECT TESTIMONY OF

JAMES W. NEELY, P.E.

ON BEHALF OF

DOMINION ENERGY SERVICES, INC.

DOCKET NO. 2021-88-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Neely and my business address is 220 Operation Way, Cayce, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Dominion Energy Services, Inc. as an Energy Market Consultant for Dominion Energy South Carolina, Inc. ("DESC" or the "Company").

Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE PLANNING IN YOUR CURRENT POSITION.

A. I am responsible for modeling DESC's electric system for the purpose of calculating avoided costs, determining the least-cost resource plan, forecasting fuel costs, and evaluating changes to electric generation.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1984 I graduated from Clemson University with a Bachelor of Science degree in electrical engineering. I received a Master of Science degree in management from Southern Wesleyan University in 2002. I received a Bachelor of Science degree from Mars Hill University in 1979. I was employed by SCE&G as a design engineer at V.C. Summer Station from 1992 to 1997. In 1997 I went to work in the SCE&G Resource Planning department as a Resource Planning Engineer. In 2013 I was promoted to Senior Resource Planning Engineer and, after the Dominion Energy merger, my title changed to Energy Market Consultant.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will discuss and present the following:

(1) DESC's avoided costs for power purchases under the Public Utility Regulatory Policies Act of 1978 ("PURPA");

(2) the long-run avoided costs for qualifying facilities ("QFs") that have production capacity up to 2 megawatts ("MW") and are set forth in the

Standard Offer Power Purchase Agreement attached to Company Witness Allen Rooks' testimony as Exhibit No. ___ (AWR-6);

(3) the short-run avoided costs for QFs that have power production capacity less than or equal to 100 kilowatts ("kW") and are set forth in Rate Schedule PR-1 attached to Witness Rooks' testimony as Exhibit No. ___ (AWR-2); and

(4) for systems above 2 MW, which by definition do not qualify for the Standard Offer or PR-1 rates, the Company's proposal is to continue calculating a project-specific avoided cost using the approved avoided cost methodology and Rate PR–Form PPA.

Q. DO THE PR-1 AND PR-STANDARD OFFER RATES APPLY TO ALL QFs THAT INTERCONNECT WITH THE COMPANY?

A. No. As summarized in Chart 1 below, Rate PR-1 applies only to QFs with a capacity of 100 kW or less, and the Standard Offer applies only to QFs with a capacity of 2 MW or less. Appropriate rates and avoided costs will be negotiated under the PR-Form PPA with QFs that are larger than 2 MW and up to 80 MW.

Chart 1
Summary of Rates and Applicable QF Capacities

Rate	Size	Time Period
PR-1	Less than or equal to 100 kW	May 2021 – April 2022
PR - Standard Offer	Less than or equal to 2 MW	2022 - 2031
PR - Form PPA	Greater than 2 MW and less than or equal to 80 MW	Appropriate 10-year period

AVOIDED COSTS UNDER PURPA

Q. WHAT DOES PURPA REQUIRE?

A. PURPA and its implementing regulations require electric utilities, including DESC, to purchase electric energy from qualifying facilities ("QF") at the utilities' avoided costs. However, state public utility commissions, such as the Commission, determine the method for calculating avoided costs, which are updated on a periodic basis. The Commission held proceedings in the early 1980s to establish the respective methodologies for determining the avoided costs of each electric utility. Determining a utility's avoided costs using an approved methodology is a process that has been ongoing for decades.

Q. WHAT ARE AVOIDED COSTS?

A. PURPA regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The Federal Energy

Regulatory Commission further recognizes that "[e]nergy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of* 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) ("Order No. 69"). In Order No. 81-214 and subsequent decisions, the Commission has recognized that utilities are entitled to recover their avoided costs paid to QFs under PURPA.

Q. ARE MARGINAL COSTS THE SAME AS AVOIDED COSTS?

A. No. Marginal costs are the cost to produce one more MW of energy above the load in each hour. As reflected in the definition of avoided costs set forth in 18 C.F.R. § 292.101(b)(6) set forth above, avoided costs are the costs that must be incurred by the Company to meet some amount of load. Marginal costs therefore do not fall within the definition of avoided costs because the utility does not need to generate or purchase energy above its load.

I further note that marginal costs are higher than avoided costs because avoided costs are the cost associated with some amount of energy below marginal

costs. In this case, avoided costs are calculated on 100 MW below the total load or below the level of marginal costs.

Q. WHAT METHODOLOGY DOES DESC USE TO CALCULATE THE ENERGY AND CAPACITY COMPONENTS OF AVOIDED COSTS?

A. As approved by the Commission in Orders No. 2016-297, 2018-322(A), 2019-847, and 2020-244, DESC uses a Difference in Revenue Requirements ("DRR") methodology to calculate both the energy and capacity components of its avoided costs. This approach follows directly from PURPA's definition of avoided costs in that it involves calculating the revenue requirements between a base case and a change case. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed a power purchase agreement. The change case is the same as the base case except that a zero-cost purchase transaction modeled after the appropriate 100 MW energy profile is assumed.

For the avoided energy cost determination, the Company uses a carefully constructed computer program called PLEXOS, which models the commitment and dispatch of generating units to serve load hour-by-hour. PLEXOS makes two runs—the base case and the change case—and estimates the production costs and benefits resulting from the purchase transaction. The base and change cases are identical except for the zero-cost purchase transaction. The avoided energy cost is the difference between the base case costs and the change case costs.

For the avoided capacity cost determination, the Company also uses the DRR methodology. For the base case, the Company calculates the incremental capital investment related revenue required to support its resource plan, either the IRP or another resource plan if more appropriate. For the change case, the Company analyzes the estimated impact that a purchase from a 100 MW facility would have on the resource plan. The avoided capacity cost is the difference between the incremental capacity costs in the base case and the change case.

Q. WHAT TIME PERIODS DOES THE COMPANY USE TO CALCULATE ITS AVOIDED COSTS?

A. To calculate avoided energy costs, the Company uses a short-term period and a long-term period. The short-term avoided energy costs are based on one year and are calculated for the period May 2021 through April 2022. The long-term avoided energy costs are calculated for calendar years 2022 through 2031. This ten-year period is divided into two groups of five years each: 2022-2026 and 2027-2031. To calculate avoided capacity costs, the Company uses a ten-year period.

AVOIDED COSTS FOR THE STANDARD OFFER RATE

Q. HOW DOES DESC CALCULATE ITS AVOIDED ENERGY COSTS FOR QF FACILITIES TAKING THE COMPANY'S STANDARD OFFER RATE?

A. The calculation of avoided energy costs for the Standard Offer follows the methodology noted above. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. The annual avoided costs are then accumulated into 11 time-of-production periods by using a profile created using the ten-year average hourly marginal costs. Avoided energy costs are calculated for calendar years 2022 through 2031. These ten years are divided into two groups of five years each: 2022-2026, and 2027-2031 for each of the 11 time-of-production periods. The change case for solar QFs is calculated by subtracting from the base case a 100 MW power purchase modeled after a solar profile. Avoided energy costs are calculated for the ten-year period 2022 through 2031, divided into the same five-year periods described above.

Q. HOW DOES DESC CALCULATE ITS AVOIDED CAPACITY COSTS FOR QF FACILITIES TAKING THE COMPANY'S STANDARD OFFER RATE?

A. To calculate the avoided capacity costs for both non-solar and solar QFs, DESC uses the DRR methodology described above to determine the incremental capital investment related revenue needed to support the appropriate resource plan using a change case that considers the impact of a purchase from a 100 MW facility. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan.

Q. WHY IS THIS METHOD REASONABLE?

A. This method identifies adjustments to the Company's expansion plan that are appropriate for calculating avoided energy and capacity costs. The cost associated with these adjustments is then quantified to reflect the capacity cost benefits that would result from the QF purchase.

Q. WHY IS IT APPROPRIATE TO USE 100MW TO ADJUST THE CHANGE CASE?

A. PURPA specifically provides that a utility may use a capacity change of up to 100 MW to calculate avoided costs. Using a capacity change of 100 MW is consistent with the calculation of avoided energy costs. Moreover, the MW change should be reflective of the MWs of QFs that the Company could expect that it would be required to purchase over the next two years, and it is reasonable to expect that several hundred MW of QFs will be built in the Company's service territory over the next two years.

Q. USING THIS METHODOLOGY, WHAT ARE THE AVOIDED CAPACITY COSTS FOR THE STANDARD OFFER RATE?

A. For non-solar QFs that qualify for the Standard Offer Rate, the avoided capacity cost is $49.89/kW-year. This avoided capacity rate will be paid during the months of December, January, and February for energy generated from 6 a.m. to 9

a.m. The annual value to be paid for each of the 270 hours (90 days x 3 hours/day = 270 hours) during this three-month period is $0.18477/kWh ($49.89/kW-yr. ÷ 270 = $0.18477/kWh).

The avoided capacity cost for solar QFs subject to the Standard Offer Rate is $2.4945/kW-year. Incremental solar QFs above the existing 973MW of existing power purchase agreements ("PPA" or "PPAs") have a 5% Effective Load Carrying Capacity (ELCC) rate, which is calculated as set forth in Exhibit No. ___ (JWN-1). Five percent of $49.89/kW-yr. is $2.4945/kw-yr. This capacity value will be paid out hourly as $0.00119/kWh ($2.4945/kW-yr. ÷ 8,760 hours[1] x 23.9% capacity factor = $0.00119/kWh).

Q. WHY IS THE ELCC RATE THAT THE COMPANY IS USING IN THIS PROCEEDING DIFFERENT FROM THE 11.8% DESCRIBED IN ORDER NO. 2020-244?

A. The 11.8% ELCC described in Order No. 2020-244 was calculated assuming only 500 MW of existing solar generation on the system. The updated calculation includes all 973 MW of existing solar PPAs that had been signed at the time of the calculation. The next 100 MW above the existing 973 MW has an ELCC of 5%. The effective load carrying capacity of incremental solar decreases as more solar is added to the system as expected for additional and similar resources.

[1] 365 days in a year x 24 hours in a day = 8,760 hours in a year.

Q. WHY IS DESC USING A TEN-YEAR PERIOD IN ITS EVALUATION OF AVOIDED COSTS?

A. It is important to recognize that projections of future avoided energy costs are uncertain. Therefore, using projected costs beyond the ten-year period required by Act No. 62 would be speculative and could increase the costs paid by DESC's customers.

Q. BASED ON THE COMPANY'S APPROVED METHODOLOGY, WHAT ARE DESC'S AVOIDED COSTS FOR THE STANDARD OFFER RATE?

A. Tables 1 through 4 below contain the avoided costs for the Standard Offer rate.

Table 1
STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11
	Dec, Jan, Feb				Mar, Apr, Oct, Nov				May- Sep		
$/kWH by 5 Year Period	5am-9am	9am-5pm	5pm-11pm	11pm-5am	5am-9am	9am-5pm	5pm-11pm	11pm-5am	11am-5pm	5pm-11pm	11pm-11am
2022-2026	0.03245	0.02599	0.03143	0.02801	0.02995	0.02580	0.03224	0.02693	0.02870	0.03260	0.02599
2027-2031	0.03651	0.02923	0.03535	0.03151	0.03369	0.02902	0.03627	0.03028	0.03228	0.03667	0.02923

Table 2
STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December, January, February 6 am to 9 am	0.18477

Table 3
STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

$/kWH by 5 Year period	All Hours
2022-2026	0.02695
2027-2031	0.02937

Table 4
STANDARD OFFER RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

Time Period	($/kWh)
All solar generating hours	$0.00119

AVOIDED COST RATE FOR SOLAR WITH STORAGE

Q. WHAT IS THE AVOIDED COST RATE FOR SOLAR WITH STORAGE?

A. Solar with storage has four avoided cost options. First, a solar with storage tariff, Rate PR-Storage, was approved by the Commission in Order No. 2020-552 issued in Docket No. 2019-393-E on August 18, 2020. This tariff is applicable to battery storage units greater than or equal to 5 MW. Storage projects qualifying for this tariff must be part of a facility comprised of a renewable generator that is either DC- or AC-coupled with the battery storage unit, and the battery storage unit must be at least 5 MW and no greater than 25% of the power production capacity of the associated renewable energy generator. The second and third options are for smaller projects: solar with storage QFs that total 2 MW or less will be eligible for the non-solar energy avoided cost rate and the non-solar capacity avoided cost for Rate PR–Standard Offer or Rate PR-1, depending on size, and will be required to pay the calculated variable integration charge ("VIC") unless certain mitigation protocols

are in place to reduce solar variability. The fourth option is Rate PR–Form PPA. Any solar with storage project above 2 MW can negotiate a PPA using the Rate PR–Form PPA.

PR-1 RATE

Q. HOW DOES DESC COMPUTE THE AVOIDED ENERGY COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. As discussed previously, DESC uses PLEXOS to estimate the change in production costs that result from serving the base case load and the change case. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. The avoided costs are set forth in Tables 5 through 8. A non-solar QF would receive an energy payment based on how much energy it produces in each of these four time-of-production periods shown in Table 5 plus a capacity payment determined by the energy produced in the winter capacity periods shown in Table 6. The energy and capacity payments for solar QFs is given in Table 7 and Table 8.

Q. HOW DOES DESC COMPUTE THE AVOIDED ENERGY COMPONENT FOR SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. DESC uses the same methodology to estimate avoided energy costs for solar QFs on PR-1 as it did for solar QFs in the Standard Offer Rate. The only difference

is the time period over which the avoided energy costs are estimated. The short-run avoided energy costs in the PR-1 Rate are calculated for the period May 2021 through April 2022 whereas the Standard Offer Rate is a ten-year calculation. Losses for PR-1 are also different. Losses for PR-1 are on calculated at the primary distribution level.

Q. DOES DESC COMPUTE THE AVOIDED CAPACITY COMPONENT FOR SOLAR AND NON-SOLAR QFs SUBJECT TO THE PR-1 RATE USING THE SAME METHODOLOGY THAT IT APPLIES FOR CALCULATING THE STANDARD OFFER AVOIDED CAPACITY COSTS?

A. Yes.

Q. WHAT IS THE AVOIDED CAPACITY COST COMPONENT FOR QFs IN THE PR-1 RATE?

A. For non-solar QFs that qualify for the PR-1 Rate, the avoided capacity cost is $49.89/kWh. It will be paid during the months of December, January, and February for energy generated from 6 a.m. to 9 a.m.

The avoided capacity cost for solar QFs that qualify for the PR-1 Rate is $2.4945/kW-year. Incremental solar QFs above the existing 973MW of existing PPAs have a 5% Effective Load Carrying Capacity (ELCC) rate. *See* Exhibit No. ___ (JWN-1) for calculation of the ELCC rate. Five percent of $49.89 is

$2.4945/kw-yr. This capacity value will be paid out hourly as $0.00119/kWh ($2.4945 ÷ (8,760 x 23.9%).

Q. WHAT ADJUSTMENTS ARE MADE TO THE AVOIDED COSTS IN THE PR-1 RATE?

A. The avoided energy cost results for both solar QFs and non-solar QFs are adjusted for line losses, working capital impacts, gross receipts taxes, and generation taxes.

Q. WHY IS THE COMPANY PROPOSING A CHANGE TO THE PR-1 TIME PERIODS FOR NON-SOLAR?

A. The previous time periods have been in place for decades and required updating to reflect the times of actual value on a system that has undergone significant changes and that experiences different demands and dispatching needs that was the case many years ago. The existing time periods were modified to reflect current system dispatch requirements and the changes in marginal costs that necessarily result from updating the system requirements.

More specifically, DESC moved May to the summer period. Summer was further modified to accommodate a one-hour shift in its coverage by changing the current 10 p.m.-10 a.m. period to be 11 p.m. to 11 a.m. With the addition of more than 1,000 MW of non-dispatchable solar added to the Company's system, the non-

summer period has changed and now experiences non-peak hours in the middle of the day. To accurately represent system characteristics, these non-peak hours were moved to the non-peak period. And based on operating experience, weekends are no longer assumed to be off-peak.

Q. WHAT IS THE RESULTING PR-1 RATE?

A. The avoided costs are shown in Tables 4 through 8 below.

Table 5
PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Non Solar	P1	P2	P3	P4
	Non-Summer: Jan, Feb, Mar, Apr, Oct, Nov and Dec		**Summer: May-Sep**	
$/kWH	5am-9am, 5pm-11pm	9am-5pm, 11pm-5am	11am-11pm	11pm-11am
May 2021 - April 2022	0.03435	0.02889	0.03338	0.02830

Table 6
PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	**($/kWh)**
December, January, February 6 am to 9 am	0.18477

Table 7
PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	**Year Round ($/kWh)**
May 2021-April 2022	0.02820

Table 8
PR-1 RATE: AVOIDED CAPACITY COST
Solar QFs ($/kWh)

Time Period	($/kWh)
All solar generating hours	$0.00119

QFs WITH CAPACITY EXCEEDING 2 MW

Q. DO THE STANDARD OFFER AND PR-1 RATES APPLY TO ALL QFS SELLING ELECTRICITY TO DESC?

A. No. The Standard Offer and PR-1 rates apply only to QFs with a size of 2 MW or less. Specifically, the Standard Offer applies to QFs of 2 MW or less and the PR-1 rate applies to QFs of 100 kW or less.

Q. HOW WILL DESC ADDRESS AVOIDED COSTS FOR QFs GREATER THAN 2 MW IN SIZE?

A. Per Act No. 62, DESC will negotiate PPAs with any QF greater than 2 MW for which the PR-1 Rate and Standard Offer Rate is not appropriate. The methodology used to calculate the avoided capacity and avoided energy costs for these QFs will be consistent with the methodology outlined previously. Other specific requirements for calculating the avoided costs for QFs greater than 2 MW in size are described in the Rate PR–Avoided Cost Methodology attached to Witness Rooks' testimony as Exhibit No. ___ (AWR-3).

VARIABLE INTEGRATION CHARGE

Q. DO CERTAIN SOLAR PPAs PROVIDE DESC WITH THE OPPORTUNITY TO RECOVER A VIC?

A. Yes. There are approximately 633 MWs of PPAs with a VIC clause that allows DESC to recover costs associated with the variable nature of solar. These costs were not captured in the avoided cost calculations that were the basis for the PPAs.

Q. ARE THERE COSTS TO DESC TO INTEGRATE THE VARIABLE ENERGY SUPPLY FROM SOLAR, AND IS IT POSSIBLE AND APPROPRIATE TO DETERMINE SUCH COSTS FOR THOSE SOLAR GENERATORS OBLIGATED TO PAY THESE COSTS UNDER EXISTING PPAs?

A. Yes and Yes. The Company experiences real and measurable costs to integrate the energy supplied by solar generators due to the variable nature of the supply. In this proceeding, Company Witness Peter David has been engaged for the purpose of calculating the VIC. For the benefit of our customers, we plan to recover these costs from solar generators whose signed PPAs include terms allowing recovery of the VIC.

Q. IN THIS PROCEEDING, IS DESC PROPOSING TO APPLY THE VIC CALCULATED BY COMPANY WITNESS PETER DAVID TO NEW PPAs?

A. Yes.

CONCLUSION

Q. WHAT IS DESC REQUESTING OF THE COMMISSION IN THIS PROCEEDING?

A. DESC respectfully requests that the Commission approve the calculation of the proposed Standard Offer avoided costs, PR-1 avoided costs, and the Company's continued use of the avoided cost DRR methodology to be used for future updates to the Standard Offer and for calculation of the avoided costs for small power producers which do not qualify for the Standard Offer PPA. DESC further requests that the Company approve the use of the VIC in new PPAs in the amounts calculated and presented by Company Witness Peter David.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

DESC 2021 Effective Load Carrying Capacity ("ELCC") Calculations for Solar Generation

Background

The ELCC is a commonly used metric for assessing the capability of a renewables generator to contribute capacity when electricity shortfalls are most likely. The calculation assumes that there is a level of solar capacity already existing on the system and that the ELCC methodology is being used to place a capacity value on an incremental level of solar capacity. The ELCC methodology assigns a capacity value based on a reliability index that measures a before and after situation. The reliability index used here is the Loss of Load Hours ("LOLH") index and the before and after situation is with and without the incremental level solar capacity.

There are multiple steps in the calculation: In Step 1 the LOLH index is calculated indicating the hours per year of expected capacity shortfall. In Step 2 the reliability impact of adding another increment of solar is calculated, which is observed by the change to the LOLH index. Typically, the LOLH index decreases indicating an increase in reliability. The goal of Step 3 is to determine the point at which the LOLH index returns to the base setting, and this is estimated by either increasing the system loads or equivalently decreasing the system capacity, Since there are 8,760 hours of system loads, it is easier to simply decrease the system capacity, which is what is done here Therefore, the ELCC capacity value of the incremental solar has a firm capacity equal to the system capacity value necessary to return the LOLH value back to the initial value. This is because the two changes to the system produce equal changes in system reliability as measured by the LOLH index.

Updated ELCC Calculation

In the context of the Company's avoided cost calculations, the system already includes 973 MW of solar capacity and the ELCC methodology will be used to place a capacity value on an additional 100 MW of solar. The following table shows the results of the 3-step ELCC evaluation process:

ELCC Results				
Step	Case	Description	Capacity	LOLH
1	Base	973 MW Solar	5,067 MW	2.86
2	Change	1,073 MW Solar	5,067 MW	2.78
3	Adjusted	1,073 MW Solar	5,062 MW	2.86
		ELCC Value	5 MW	5%

The table shows that when adding 100 MW of solar capacity to the existing 973 MW, which produces a total of 1,073 MW of solar capacity, the system becomes more reliable as indicated by the decrease in the LOLH index to 2.78 hours. In Step 3, decreasing the system capacity by 5 MW decreases reliability and returns the LOLH index back to the initial level of 2.86 hours. Decreasing system capacity by more than 5 MW increases the LOLH beyond its initial level, and decreasing it by less than 5 MW does not return the LOLH to its initial level. Therefore, the ELCC capacity value of the incremental 100 MW of solar capacity is 5 MW, which is 5% of solar nameplate. Thus, the ELCC is 5%.